REVISED DIRECT TESTIMONY AND EXHIBIT OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2021-88-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada, and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1. My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;
- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;

- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering ("NEM") program revisions in California.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I previously testified before this Commission on behalf of the Office of Regulatory Staff ("ORS") in previous proceedings for Annual Review of Base Rate for Fuel Costs (Docket Nos. 2017-2-E, 2018-2-E, 2019-2-E), Avoided Cost (2019-185-E, 2019-186-E), and Establishment of Solar Choice Metering Tariff (2020-229-E, 2020-264-E, 2020-265-E).

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analysis, review, and develop recommendations regarding the following filings and issues in this proceeding:

1) Rate PR-1 proposed by Dominion Energy South Carolina, Inc. ("DESC");
2) DESC's proposed Rate PR - Standard Offer;
3) DESC's proposed Rate PR- Form PPA;
4) DESC's proposed avoided cost methodologies;
5) DESC's proposed commitment to sell forms;
6) Consistency of the avoided cost methodology with the Public Utility Regulatory Policies Act of 1978 ("PURPA") requirements;
7) The reasonableness of the avoided energy and capacity cost rates requested by the Company;

8) Whether the solar variable integration charge ("VIC") requested by the Company is reasonable and quantified correctly; and

9) Any other terms or conditions necessary to implement S.C. Code Ann. § 58-41-20 enacted as part of of the South Carolina Energy Freedom Act ("Act 62" or the "Act").

Q. WHAT GUIDING PRINCIPLES DID YOU APPLY IN YOUR REVIEW OF THE COMPANY'S FILING IN THIS DOCKET?

A. My review and resulting recommendations are based on standard industry principles for the establishment of avoided costs for electrical utilities. These principles are clearly represented in section 58-41-20(A) of Act 62, which mandates that the Commission's decisions in these proceedings "… shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's [("FERC")] implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."

Q. IN YOUR OPINION, WERE THE COMPANY'S FILINGS IN THIS DOCKET REASONABLY TRANSPARENT FOR YOUR INDEPENDENT REVIEW AND ANALYSIS?

A. Yes. The Company provided information in its filings and data responses that allowed me to assess the reasonableness of its proposals, to make important improvements to the assumptions, and follow those changes through the models so that I could derive my recommended tariffs and PPA rates.

Q. BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW THEY RELATE TO RATE PR-1 AND RATE PR-STANDARD OFFER ("STANDARD OFFER") PROPOSED BY THE COMPANY.

A. In 1978, as part of the National Energy Act, Congress passed PURPA. The policy was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.

To help accomplish PURPA goals, a special class of generating facilities called qualifying facilities ("QFs") was established. QFs receive special rate and regulatory treatments, including the ability to sell energy and capacity to electric utilities. All electric utilities, regardless of ownership structure, must purchase energy and/or capacity from, interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets.

In DESC's service territory, Small Power Producers and Cogenerators that are designated as QFs and have capacity less than or equal to 2 megawatts ("MW") are compensated under the Rate PR-Standard Offer. QFs with capacity greater than 2 MW and less than or equal to 80 MW are compensated under the Company's proposed PR-Form PPA.

Q. PLEASE RESPOND TO WITNESS NEELEY'S ASSERTION (DIRECT, P. 5) THAT MARGINAL COSTS DO NOT FALL WITHIN THE DEFINITION OF AVOIDED COSTS.

A. I have been working in the area of marginal and avoided costs for over thirty (30) years. Throughout my career I have seen various uses of the terms "marginal costs," "avoided costs," "incremental costs," and even "decremental costs." In the vast majority of cases, these terms are used in a loose fashion, with an emphasis on readability rather than precision. I believe that Witness Neely arrived at his incorrect assertions from an overly close reading of imprecise definitions.

Witness Neeley's finding that marginal costs do not fall within the definition of avoided costs hinges on his observation that marginal costs are for increases in output, while avoided costs are for decreases in output. The problem is that Witness Neely bases his interpretation of marginal costs on a definition that is incomplete. He states that "marginal costs are the cost to produce one more MW of energy above the load in each hour." This is a common way marginal costs are described for ease of comprehension. The precise definition, however, is marginal cost equals the first derivative of the total cost function.[1] A more accurate definition therefore is marginal costs are the change in costs due to a change in output. As such, the marginal cost is the slope of the total cost curve at a certain output level and applies equally to an increase or decrease in output.

The application of marginal costs equally to increases or decreases in load is acceptable in the estimation of avoided costs. Similarly, incremental or decremental costs are also acceptable methods.

I. Variable Integration Charge Analysis, Discussion, and Recommendations

[1] https://economics.uwo.ca/math/resources/derivatives/7-derivative-uses-in-economics/content/
http://math.hawaii.edu/~mchyba/documents/syllabus/Math499/extracredit.pdf
http://www.columbia.edu/itc/sipa/math/calc_econ_interp_u.html

Q. DOES THE EFFICIENT INTEGRATION OF RENEWABLE ENERGY GENERATION CREATE ADDITIONAL COSTS FOR UTILITIES?

A. Yes. E3 conducted extensive work in California and Hawaii where renewable generation comprises a large portion of the utility's generation resources. In our modeling, E3 observed that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. The cost impact may include higher start-up costs, fuel costs, and operating and maintenance ("O&M") costs resulting from resources operating at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs may also increase for additional generation plant required to provide additional flexible capacity.

Q. BRIEFLY EXPLAIN THE COMPANY'S METHODOLOGY FOR CALCULATING THE VARIABLE INTEGRATION CHARGE.

A. First, the Company estimates the additional amount of operating reserves that should be carried because of the output uncertainty of solar generators on the DESC system. The uncertainty is simulated using differences between 4-hour ahead scheduled generation and actual generation from National Renewable Energy Laboratory's ("NREL's") Solar and Wind Integration Data Sets. Monthly operating reserve levels are then determined by DESC based on the 90th percentile of North American Electric Reliability Corporation ("NERC") violations observed in Monte Carlo simulations for each month. Finally, the Company runs two (2) PROMOD production simulations --- one with a normal operating reserve requirement, and a second with a higher than normal operating reserve requirement. The VIC is the amount of increased operating costs in the higher operating reserve simulation.

Q. IN YOUR OPINION, IS THE COMPANY'S METHODOLOGY TO CALCULATE RENEWABLE INTEGRATION COSTS REASONABLE?

A. Yes. I find the overall concepts of the calculation methodology used in the Guidehouse Variable Integration Study to be reasonable.

Q. SHOULD THE COMPANY'S PROPOSED VIC CHARGES BE ADOPTED BY THE COMMISSION?

A. No, not at this time. DESC first proposed a version of the calculation methodology in Docket No. 2019-184-E. In that proceeding, ORS through my testimony and other parties raised concerns with the analysis and assumptions used by DESC and Guidehouse (formerly known as Navigant). Guidehouse appears to have addressed some of the concerns raised by ORS and the other parties in the new analysis including the reduction or elimination of the need for additional operating reserves in hours where solar is expected to be generating at low or zero levels. However, through my review of the Company's calculation methodology, I find that Guidehouse has not justified their forecast of incremental operating reserves needed to accommodate solar forecast uncertainty.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE COMPANY'S TREATMENT OF SOLAR FORECAST UNCERTAINTY.

A. Solar forecast uncertainty is the primary driver of the Company's need for increased operating reserves. The risk of solar output being lower than scheduled or forecasted levels necessitates having flexible generation available to keep the system in balance. Generally, the more flexible resources that the Company needs to be spinning or available to respond to drops in solar output, the higher the cost of the generation.

The Company's solar forecast study models forecast uncertainty of solar output based on the differences between 4-hour ahead schedules and actual solar output. The study recognizes that ideally 1-hour ahead schedules would be used, but the data for 1-hour ahead was not available (Direct Testimony of Peter B. David, p. 9). The ability of the Company to increase its forecast accuracy depends upon the specific forecasting method used, and a 2015 study suggests that solar forecast errors could be reduced by about half if 1-hour ahead schedules are used.[2]

To its credit, the Company attempted to correct for the excessive solar forecast error in the 4-hour ahead forecasts by excluding the 10% largest violations in the determination of the need for incremental operating reserves. However, neither the Company's study nor the DESC testimonies and data responses provide sufficient information to support that excluding the top 10% violations results in estimates of incremental operating reserves that closely match current or future DESC operations.

Q. DOES ORS HAVE A RECOMMENDATION RELATED TO THE VIC?

A. Yes. I propose the VIC remain at \$0.96/MWh and remain subject to a future true up as contemplated in Order No. 2020-244. The DESC Amended Application in this docket states on page 9 as follows:

> The Commission also approved in Order No. 2020-244 a variable integration charge ("VIC") of \$0.96/MWh for Solar QFs as a "temporary, interim value until a more accurate cost can be determined through an

[2] Zhang, Jie, et al. "Baseline and target values for regional and point PV power forecasts: Toward improved solar forecasting." Solar Energy 122 (2015): 804-819. Estimate of roughly half reduction in forecast error based on Smyrna Tennessee and ISO-NE statistical metrics of root mean square error, maximum absolute error, standard deviation, and 95th percentile of error.

> integration study," and further directed that, "[o]nce a more accurate rate is determined, the VIC/EIC will be subject to a true-up, either up or down, depending on the actual integration cost indicated by the integration study." Pursuant to S.C. Code Ann. § 58-37-60, which authorizes the Commission to conduct an integration study using its own consultant, the Commission in Order No. 2020-583 directed the Clerk to "open a new docket or dockets for consideration of the utility integration studies," which was done for DESC in Docket No. 2020-219-A, "Utility Integration Studies of Dominion Energy South Carolina, Incorporated (Pursuant to Commission Directive Order No. 2020-583)." The process contemplated in Docket No. 2020-219-A remains pending.

Given that the Commission has already determined that the VIC should be informed by the Commission study referenced in Order No, 2020-244, it would be premature to adopt new VIC values at this time. Moreover, through the extension of the true-up provision, any deviations from the actual integration costs may be addressed.

II. Avoided Energy Analysis, Discussion, and Recommendations

Q. DESCRIBE THE METHODOLOGY THE COMPANY USED TO CALCULATE PROPOSED AVOIDED ENERGY COSTS.

A. As described by Company witness Neely in his Direct Testimony (p. 8), DESC calculates avoided energy costs using a methodology known as the Differential Revenue Requirement ("DRR"). The DRR method calculates the revenue requirements associated with two (2) different resource plan scenarios: a base case without a QF, and a change case with a QF.

For the long-run avoided energy cost calculations, in both the base case and the change case, DESC uses PLEXOS, a production cost model, to simulate the commitment of generating units to serve load on an hourly basis over a 15-year Integrated Resource Plan ("IRP") planning horizon. The base case is constructed by using load forecasts and supply side resources as described in the IRP. The change case modifies the base case load forecasts and supply side resources by modeling the addition of 100 MW of solar generation to measure the reduction in energy costs equal to the impact of adding 100 MW of solar to DESC's supply side resources. For non-solar QFs, the change case modifies the base case by modeling the addition of a 100 MW block of generation available around the clock. Finally, the avoided energy costs are levelized and adjusted for taxes and working capital.

Q. DOES THE DRR METHOD USED BY THE COMPANY TO CALCULATE AVOIDED ENERGY COSTS COMPLY WITH PURPA AND WITH THE METHODOLOGY PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. The DRR method is one of the generally accepted methods for calculating PURPA avoided energy costs and is used throughout the United States. It is the same methodology used by DESC in Docket No. 2019-184-E and approved by the Commission in Order No. 2019-847. The Company's use of a solar profile is reasonable to use for solar specific QFs.

Q. PLEASE SUMMARIZE THE TIME OF USE ("TOU") PERIODS PROPOSED BY DESC FOR THE PR-1 RATE.

A. For the PR-1 Rate available to small power producers and cogenerators at or below 100 kilowatts ("kW"), DESC calculated avoided energy costs for one year, May 2021 to April 2022. The PR-1 rate provides different energy credits for non-solar and solar generators.

For the non-solar QFs, DESC proposes to continue using two (2) seasons, summer and non-summer, but with a modification to the summer season to include the month of May (season starts in May and ends in September). The non-summer season includes all other months. Within the summer season, DESC retains two (2) time of day periods, with a slightly modified on-peak period that continues to be twelve (12) hours long but starts and ends an hour later (11:00 am to 11:00 pm). The non-summer season also continues to have two (2) TOU periods, but DESC proposes to exclude late morning and early afternoon hours from the peak period so that peak hours only include 5:00 am through 9:00 am (as opposed to 6:00 am to 1:00 pm) and 5:00 pm to 11:00 pm (as opposed to 5:00 pm to 10:00 pm).

For the PR-1 solar-specific rate, DESC proposes to eliminate any time of day differentiation and seasonality. DESC proposes to use a single, flat per- kilowatt hour ("kWh") energy credit. This flat energy credit reflects the result of the DRR analysis. The credit is the total annual DRR cost savings from a solar generator, divided by the annual output of that generator.

Q. WHY ARE FOUR (4) TOU PERIODS FOR NON-SOLAR GENERATORS AND THE USE OF A SINGLE FLAT CREDIT FOR SOLAR GENERATORS REASONABLE FOR THE PR-1 RATE?

A. Four (4) TOU periods are reasonable for the small non-solar generators that would be eligible for PR-1 rate because the DESC marginal energy costs show only moderate variation by hour of the day within the summer and winter seasons. I believe it is reasonable to employ relatively simple TOU periods for small non-solar generators in order to minimize customer confusion and promote rate simplicity. As discussed later in my direct testimony, I propose a refinement of the four (4) TOU periods to better reflect the variations that exist in the marginal energy costs.

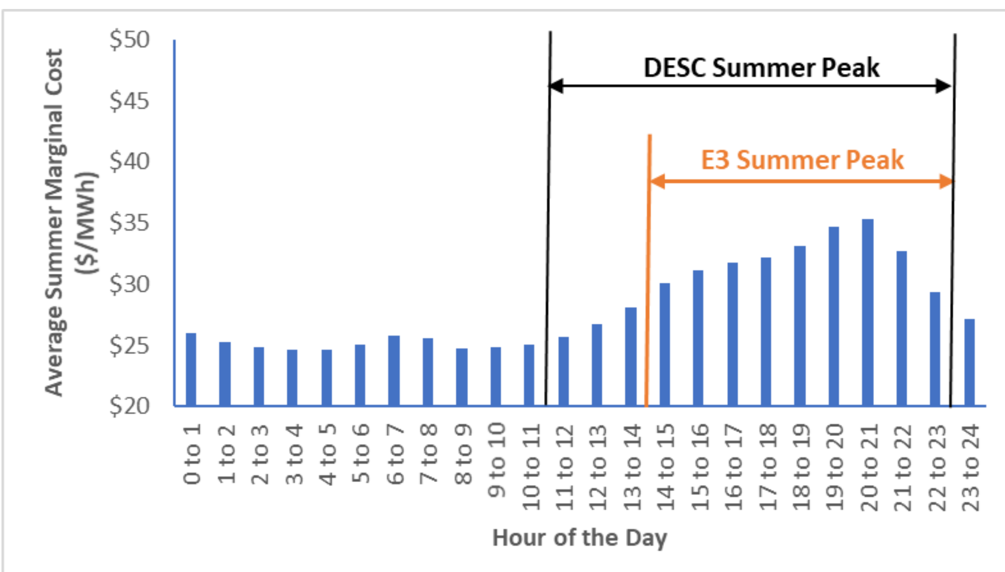
It is reasonable to use a single energy credit for all output from solar generators under the PR-1 rate. To be sure, the value provided by solar generation varies across the time of day and season, but those variations are captured and averaged over the entirety of solar output in setting the solar specific single energy credit.

Q. WHY DO YOU PROPOSE A MODIFICATION TO THE FOUR (4) TOU PERIODS FOR NON-SOLAR GENERATORS ON THE PR-1 RATE?

A. DESC's proposal is an improvement over the current TOU periods. However, a more focused peak period (the proposal has an 11:00 am to 11:00 pm peak period) would provide even greater incentives for generators to provide power when it is most valuable to DESC and its retail customers.

A review of DESC's 2022 hourly energy marginal costs shows that the average summer marginal costs between 11:00 am and 2:00 pm are significantly lower than the average costs for the other peak hours. This is shown in the figure below.

Figure 1: Average Summer (May through Sept) 2020 DESC Marginal Energy Costs



Note: Costs are shown prior to adjustments for working capital, generation tax, gross receipts, and losses.

I recommend the Company shift the summer hours of 11:00 am to 2pm from the summer peak period to the summer off-peak period. The shift to move the summer hours of 11:00 am to 2:00 pm to the summer off-peak period increases the average summer peak marginal cost and increases the accuracy of the TOU averages by 3% over the entire year.[3]

Q. WHY IS IT APPROPRIATE FOR DESC TO USE A SINGLE ENERGY CREDIT THAT IS SPECIFIC TO SOLAR GENERATORS INSTEAD OF USING AVERAGE ENERGY CREDITS BY TOU PERIOD?

A. In an economist's ideal world, the energy credits would vary hourly in order to match the Company's marginal energy costs. The hourly costs would provide the most precise price signals to generators and provide the most precise compensation to those generators in line with the value they provide to DESC and its customers. It is common in the industry, however, to set prices that do not vary hourly, but instead vary by four to six TOU periods. This is done to aid customer understanding of the rates.

TOU energy rates would be just as precise as hourly prices if 1) energy costs did not vary within a TOU period, or 2) customer generation did not vary within a TOU period. To the extent that costs and generation do vary, TOU prices could over or under compensate customers. If the variations in costs and/or generation are random, then the over and under compensation would tend to balance out over the year. However, in the case of solar generation and DESC costs, the variations in costs and generation are not random.

[3] I define accuracy as the degree to which the TOU average cost matches the hourly costs contained in that TOU period. I calculate accuracy as the sum of the absolute value of the deviations between the average cost in the TOU period and each hourly cost in the TOU period. In this way positive and negative deviations are valued equally. The smaller the total absolute value deviations over all hours of the year, the more accurate the average costs from the TOU periods. Moving the three hours of 11:00 am to 2:00 pm provided the largest reduction in deviations among the myriad of four TOU period variations that I tested.

To quantify the overcompensation from using the existing four (4) TOU periods for solar generators, I compared 1) the total annual energy credits a solar generator would receive using hourly avoided energy cost credits and 2) the annual credits that same generator would receive using four (4) TOU credits that are the average of the hourly avoided costs in each TOU period. For this analysis I used a default solar output shape for Columbia, South Carolina from NREL's PVWatts online tool,[4] and DESC's 2022 hourly marginal energy costs. My analysis showed that using average energy credits by the four (4) current TOU periods would overcompensate solar generators by 9~~7~~%.

The DESC proposal to use a single solar-specific energy credit for the PR-1 solar energy credit and the Standard Offer solar energy credit solves the TOU overcompensation because it specifically estimates the annual value of solar generation through the DRR process, and divides that value by the annual solar output. In this way it eliminates the averaging problem inherent in the TOU credits. Of course, actual solar generators will have output patterns that deviate somewhat from that used in the DDR modeling, but using the single credit based on a typical solar output pattern is still preferrable to an alternative such as the four (4) TOU credits.

Q. PLEASE DESCRIBE DESC'S PROPOSED TOU PERIODS FOR STANDARD OFFER RATES.

A. For the Standard Offer Rate DESC calculated avoided energy costs for a 10-year timeframe (2022 through 2031) and levelized those avoided costs for the first and the second half of the period, i.e., years 2022-2026 and 2027-2031. For the *solar* PR -Standard

[4] This online tool is available at https://pvwatts.nrel.gov/.

Offer rate, DESC uses a single rate for each of the 5-year timeframes within the 10-year period.

For the non-solar Standard Offer rates, DESC proposes eleven (11) TOU periods, compared to four (4) TOU periods in the current Standard Offer tariffs. As described in Company witness Neely's testimony (p. 12), DESC identifies May – September ("Summer"), December through February ("Winter") and a third season with the remaining months of March, April, October and November ("Shoulder"). Within these seasons, DESC proposes three (3) TOU periods in the Summer season, and four (4) in the Shoulder and the Winter seasons. The Summer and Shoulder seasons' peak periods are from 5:00 pm to 11:00 pm, while in the Winter season, DESC estimates the highest avoided energy costs to occur in the morning, from 5:00 am to 9:00 am, at a level only slightly lower than that of the Summer's highest price.

Q. DO YOU RECOMMEND ANY CHANGES TO DESC'S PROPOSED STANDARD OFFER TARIFF TOU PERIODS FOR NON-SOLAR GENERATORS?

A. No, the TOU periods for the Standard Offer rate for non-solar are reasonable, and the higher granularity will help incentivize generators to export energy in hours of highest value to DESC.

Q. DO YOU HAVE ANY CHANGES TO DESC'S PROPOSED SINGLE ENERGY CREDIT FOR SOLAR GENERATORS ON THE STANDARD OFFER RATE?

A No. As with the PR-1 energy rate for solar generators, it is reasonable for the Standard Offer rate for solar generators to not have TOU periods since the solar Standard Offer avoided energy cost is specific to the DRR solar QF analysis.

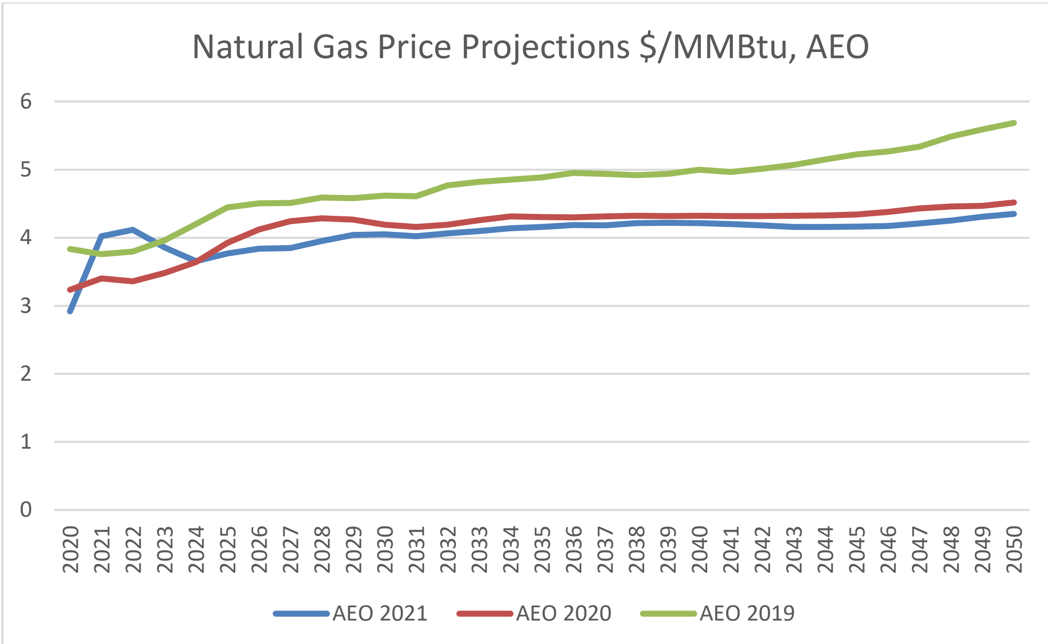
Q. PRIOR DISCUSSIONS FOCUSED ON TOU PERIOD CHANGES. DO YOU CONSIDER THE OTHER UPDATES TO THE AVOIDED ENERGY COSTS TO BE REASONABLE AND CONSISTENT RESULTS OF THE METHODOLOGY USED BY THE COMPANY?

A. Yes. DESC applied the approved DRR methodology to calculate avoided energy costs in a manner consistent with past filings of avoided energy rates. I compared the updated avoided energy credits with the avoided energy credits approved in Docket No. 2019-184-E and Order No. 2020-244, and reviewed the fuel price forecasts provided by the Company in both this docket and in Docket No. 2019-184-E.

DESC's proposed PR-1 energy credits for solar generators would provide about a 7% reduction in energy credit compensation compared to the current rates. Similarly, the proposed Standard Offer energy credits over the entire 10-year period average 6% lower than under the current tariffs. These reductions are consistent with the shift from TOU energy credits (about a 9~~7~~% reduction), and the changes observed in fuel price forecasts. Figures 2 and 3 show that the Energy Information Agency's Annual Energy Outlook ("AEO") natural gas and coal price forecasts are slightly lower over the 10-year period than those in AEO's 2020 and 2019 forecasts.

The proposed non-solar PR-1 energy credits increase by about 3% relative to the current energy credits. This increase is consistent with the near-term increase in natural gas prices shown in the recent AEO forecast and also reflected in the New York Mercantile Exchange (NYMEX) electricity price forwards. The non-solar Standard Offer energy credits increase by about 1% over the 10-year applicability period, which is consistent with the relatively flat annual price escalations in the recent AEO forecasts.

1 ***Figure 2. Natural Gas Price Projections, AEO***[5]



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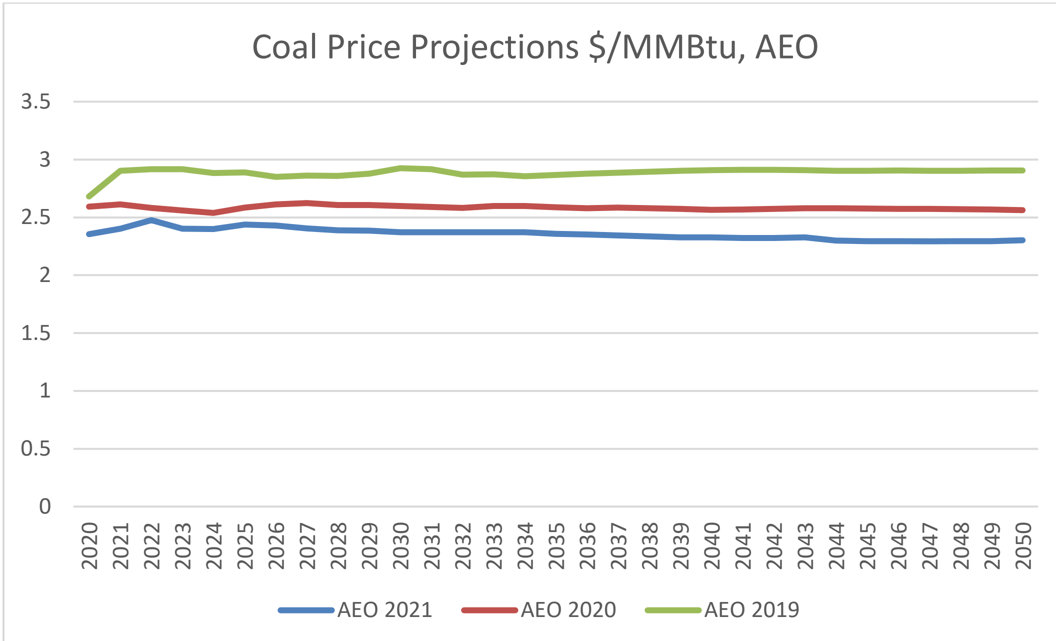
[5] Note AEO 2021 and AEO 2020 are graphed in 2020 dollars, AEO 2019 are graphed in 2019 dollars.

***Figure 3. Coal Price Projections, AEO*[6]**



Q. DOES ORS RECOMMEND THE COMMISSION APPROVE DESC'S ESTIMATES OF AVOIDED ENERGY COSTS AND RESULTING PR-1 AND PR-STANDARD OFFER ENERGY CREDITS?

A. Yes. ORS recommends the Commission approve DESC proposed avoided energy costs for the following rates:

- PR-1 for solar;
- Standard Offer for solar; and
- Standard Offer for non-solar.

Q. WHAT ARE YOUR RECOMMENDED TOU ENERGY CREDITS FOR NON-SOLAR PR-1 GENERATORS?

[6] Note AEO 2021 and AEO 2020 are graphed in 2020 dollars, AEO 2019 are graphed in 2019 dollars.

A. Table 1 shows ORS recommended energy credits. These credits are calculated using the recommended TOU periods and the DESC methodology and assumptions that incorporate the additional costs and adjustments for working capital, generation tax, gross receipts and losses.

Table 1: PR-1 Non-Solar Energy Credit ($/kWh)

Non-Summer: Jan-Mar & Oct-Dec		Summer: May-Sep	
5am-9am, 5pm-11pm	9am-5pm, 11pm-5am	2pm-11pm	11pm-2pm
0.03437	0.02805	0.03608	0.02875

III. Avoided Capacity Analysis, Discussion, and Recommendations

Q. PLEASE DESCRIBE THE METHODOLOGY THE COMPANY USED TO CALCULATE PROPOSED AVOIDED CAPACITY COSTS.

A. DESC calculated the avoided cost of capacity using the DRR method. The capacity cost calculation starts with the difference in fixed costs for a base resource plan compared to a resource plan with an additional 100 MW of generation capacity ("Change Case"). The additional 100 MW of generation allows for the deferral of planned new generation resources. The cost savings associated with the deferral of new resources are then divided by the assumed 100 MW of generation capacity in the Change Case and levelized to calculate the avoided capacity cost.

Q. DOES THE METHODOLOGY USED BY THE COMPANY TO CALCULATE AVOIDED CAPACITY COSTS COMPLY WITH PURPA AND THE METHODOLOGY PREVIOSLY APPROVED BY THE COMMISSION?

A. Yes. The DRR methodology is one of the generally accepted methods for calculating PURPA avoided capacity costs and is used throughout the United States. It is the same methodology used by DESC in Docket No. 2019-184-E and approved by the Commission in Order No. 2019-847.

Q. WHAT VALUES DOES DESC PROPOSE FOR AVOIDED CAPACITY COSTS?

A. DESC proposes a value of $0.00119/kWh for avoided capacity costs for incremental solar projects for the Rate PR-Standard Offer. For non-solar projects the Company proposes an avoided capacity cost rate of $0.18477/kWh for the proposed Rate PR- Standard Offer.

Q. PLEASE EXPLAIN WHY YOU DO NOT AGREE WITH THE COMPANY'S AVOIDED CAPACITY VALUES.

A. While I agree generally with the Company's methodology and assumptions, two (2) corrections should be made by DESC in order to prevent underestimation of the value of generation capacity. The first correction is to use 66 MW as the assumed capacity change used in the Change Case so that it is the same as the assumed size of a new generating unit used by DESC in the analysis. Currently, DESC assumes a 100 MW capacity change in their Change Case yet models meeting that 100 MW change with 66 MW generators. The mismatch in generator sizes biases the avoided capacity cost downward. Eliminating the mismatch by using 66 MW for the capacity change and the generator size increases the avoided capacity cost by 17%.

The second correction I recommend is that DESC should use 2022 as the reference year for the avoided cost calculations. The Company's workpapers demonstrate their calculations rely upon 2020 as the reference year, which results in an 18% underestimation of the avoided capacity cost. In total, the two (2) corrections I recommend DESC include in the calculation of avoided capacity values would increase the avoided cost capacity costs by 38%.

Q. HAS THE COMMISSION ADOPTED ORS'S RECOMMENDATION TO ENSURE THE GENERATION CHANGE IS CONSISTENT WITH THE NEW GENERATOR SIZE?

A. Yes. In Docket No. 2019-184-E, DESC used a 100 MW generation change in the Change Case and used a 93 MW new generator size. The Commission adopted the recommendation from ORS to set the Change Case capacity change at the same size as the modeled new generation (Order No. 2019-847, pp. 24-25). The Company did not request reconsideration or appeal Commission Order No. 2019-847.

In Docket No. 2019-184-E, I noted that because of the unevenness of the size of combustion turbine ("CT") additions, avoided capacity costs could easily be manipulated up or down through mismatches in capacity changes and CT sizes. For example, I could increase the avoided capacity factor by almost a factor of 18 (from \$0.24725/kWh to \$4.3925/kWh in Docket No. 2019-184-E) by using a 15 MW capacity change with a 93 MW CT plant size.

To avoid such manipulations to the avoided capacity factor, the DRR method should equally match the capacity change for the Change Case with the size of the CT additions. I recommend in this docket to use a 66 MW capacity change to be consistent with DESC's modeled new CT generator.[7]

[7] Alternately, one could use a CT plant with hypothetical 100 MW capacity with a hypothetical 100 MW Change Case, but in either scenario the Change Case capacity reduction should be the same as the size of the CT plant.

Q. PLEASE EXPLAIN WHY IT IS NECESSARY TO CHANGE THE REFERENCE YEAR USED IN THE DRR CALCULATIONS FOR AVOIDED CAPACITY COSTS.

A. The DRR method calculates the avoided cost of capacity based on the difference in the present values of the capacity-related revenue requirement of the base case minus the change case. The present value calculations are used to convert future cash flows to an equivalent value in a reference year. DESC used a reference year of 2020 for the DRR calculations; however, a more appropriate year is 2022 because this docket is determining avoided capacity values for 2022.

The choice of the reference year is impactful because use of a reference year other than 2022 will arbitrarily decrease or increase the DRR avoided capacity cost result. For example, using a reference year of 2010 would reduce the avoided capacity cost by almost 63% relative to a 2022 reference year, while using a reference year of 2030 would increase the avoided capacity cost by over 93%.[8]

By assigning a reference year of 2020, DESC reduces the DRR avoided capacity cost by approximately 18% compared to the avoided capacity cost using a reference year of 2022. Since this docket is setting avoided capacity costs for use in 2022 tariffs, ORS recommends that 2022 be used for the reference year of the present value calculations, and thereby match the avoided capacity costs with when the associated tariffs will be effective.

[8] Based on the DESC discount rate of 8.58%,. 2010 result = (1/(1.0858)^(2022-2010))-1, and 2030 result = 1(1/(1.0858)^(2022-2030))-1.

Q. PLEASE PROVIDE THE IMPACT OF THE ORS RECOMMENDATIONS ON THE STANDARD OFFER AND PR-1 GENERATION AVOIDED CAPACITY CREDITS.

A. Table 2 below shows DESC's proposed generation capacity credits and the ORS recommended correction for avoided capacity credits. The ORS recommended credits were derived using DESC's workpaper electronic spreadsheet models reflecting the recommendations to use 66 MW generation capacity change and the DRR reference year of 2022 instead of 2020. The result of applying both ORS recommendations is a 37.5% increase in the avoided capacity rates as shown below.

Table 2: ORS Avoided Capacity Rate Recommendations

Applicability	Time Period	DESC Proposal ($/kWh)	ORS Recommended ($/kWh)
Non-Solar	Dec, Jan, Feb, 6am to 9am	0.18477	0.25413
Solar QFs	All Hours	0.00119	0.00164

Note: From Neeley Direct, Tables 2 and 4

Q. PLEASE EXPLAIN WHY THE AVOIDED CAPACITY CREDITS (ON A $/KWH BASIS) FOR SOLAR QFS ARE SUBSTANTIALLY LOWER THAN THE CREDITS FOR NON-SOLAR GENERATORS.

A. The solar QF $/kWh credit is lower than the non-solar QF $/kWh credit for two (2) reasons. First, the non-solar QFs are only credited for output from 6:00 am to 9:00 pm in three (3) winter months. In contrast, the solar QFs receive a capacity credit for all of their output, regardless of the time of day or the season. Second, the credit provided to solar QFs is reduced for the fact that the generation capacity reduction per nameplate kW of solar generation is decreasing with higher levels of solar penetration on the DESC system. In

Docket No. 2019-184-E, 11% of solar nameplate capacity was counted toward generation capacity reductions based on Effective Load Carrying Capability ("ELCC") studies. In this docket, DESC estimated that the ELCC-based value is now only 5% of nameplate capacity.

Q. IS IT APPROPRIATE FOR DESC TO RELY ON ELCC TO DETERMINE THE CAPACITY CONTRIBUTION OF INTERMITTENT RESOURCES SUCH AS SOLAR?

A. Yes. ELCC analyses were developed in the electric industry specifically for the purpose of determining capacity contributions from intermittent resources.[9]

E3 has been a leader in evaluating the impact of renewable resources on utility planning and operations. Through E3's work, it is abundantly clear that resources such as wind and solar generation must be evaluated using probabilistic methods such as those used in ELCC analyses. It is also clear that with increasing levels of solar resources on the grid, the capacity value of incremental solar resources can decline as utility needs for incremental generation capacity shift away from summer daytime hours.

IV. Other Avoided Capacity Values

Q. DOES ORS RECOMMEND THE AVOIDED COSTS FOR THE COMPANY INCLUDE CAPACITY AVOIDED COSTS FOR TRANSMISSION AND DISTRIBUTION ("T&D")?

A. No, not at this time. While ORS does support the inclusion of T&D avoided capacity costs in many applications, they should not be considered for inclusion in the avoided costs adopted herein until the Commission issues its final order in Docket No.

[9] For example, see the NREL report, *Using Wind and Solar to Reliably Meet Electricity Demand,* https://www.nrel.gov/docs/fy15osti/63038.pdf.

2019-182-E. Moreover, even if an Order were issued prior to completion of this docket, there is a lack of Company specific information on the record in this docket or Docket No. 2019-182-E related to details such as the allocation of T&D capacity costs to TOU periods, or the effect of the intermittency of generation resources on the reliable capacity of the resources toward T&D capacity need reduction. Without such information and the opportunity to review the information, it would be premature to include T&D capacity avoided capacity costs into the tariffs adopted herein.

Q. DESC'S RATE PR – AVOIDED COST METHODOLOGY (EXHIBIT AWR-3) STATES THAT TRANSMISSION CAPACITY AND DISTRIBUTION CAPACITY AVOIDED COSTS WILL BE DETERMINED BASED ON ENGINEERING ASSESSMENTS ON A PROJECT-BY-PROJECT BASIS. DOES THIS APPROACH SUFFICIENTLY COVER THE AVOIDED COSTS OF T&D CAPACITY?

A. No, not necessarily. If the Commission decides in Docket No. 2019-182-E that non-zero avoided T&D capacity costs should be included in the credits for small generators, then those T&D credits should be used as the default values for all QFs under Rates PR-1, PR-Standard Offer, and PR-Form PPA rates. If an engineering study for a particular project or portfolio of projects indicates a higher T&D credit is warranted, then the higher value should replace the default T&D value.

The reason the default values are needed (if adopted) is due to small projects similar to those eligible for the Standard Offer which are likely too small to affect the T&D plans individually. However, in combination with other generators and demand-side activities, the aggregate impacts of small projects can have a material impact. By requiring each individual project to provide value on its own, one could miss the actual value or misallocate the credits.

Consider a distribution area that has a new retail cluster slated for completion in three (3) years. Because of the new large load, the area will need a new substation, but if 3 MW of peak reduction can be found, then the substation could be deferred for five (5) years. If DESC evaluates two (2) QFs, both 2 MW, on a case-by-case basis, neither would be able to reach the 3 MW need, and there would be no T&D capacity credit --- even though they would be able to defer the substation if considered together. Now, if both projects are on the same engineer's desk at the same time, then perhaps they could be bundled together and the benefit shared between them. But what if there is only one 2 MW generator and 2 MW of demand-side measures for the area? Without tight coordination across multiple departments, the engineer evaluating the QF may not know that it could defer the substation as part of a larger portfolio and would assign zero T&D capacity credit to the QF. Also, consider the case where one 2 MW QF is built this year, and another 2 MW QF next year. In that case, the first QF would receive no T&D capacity credit (because it could not defer the substation), but the second QF would receive a T&D credit. One could argue it is not equitable for the first QF to receive no T&D credit, since the substation deferral required both the first and second QF. However, the engineer would not be able to anticipate the second QF when evaluating the first, so the T&D credit would have to be zero according to Exhibit AWR-3.

The above examples represent a few of the myriad of issues with doing case-by-case analyses for small generators. Adopting default non-zero T&D capacity values would help address these issues.

V. Summary of Recommendations

Q. PLEASE PROVIDE A SUMMARY OF THE ORS RECOMMENDATIONS.

A. ORS offers the following recommendations for the Commission's consideration:

1) Reject DESC's proposed VIC amounts of $1.80/MWh for the first tranche of solar, which ranges from 341 MW to 973 MW, and $3.43/MWh for the second tranche of solar and maintain the current VIC of $0.96/MWh value with an opportunity for a future true-up in accordance with Order No. 2020-244;
2) Reject DESC's PR-1 TOU energy credits for non-solar generators;
3) Adopt the ORS recommended PR-1 TOU energy credits for non-solar generators that better reflect the variation in DESC marginal energy costs;
4) Reject DESC's avoided capacity rates for both solar and non-solar QFs; and
5) Approve the ORS recommended avoided capacity rates that correct the generation capacity change to 66 MW and correct the DRR reference year to 2022 instead of 2020.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR REVISED DIRECT TESTIMONY?

A. Yes, it does.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the "E3 Calculator" tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model's sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA
B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
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15. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*
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3. *Horii, B., R. Orans, A. Olsen, S. Price and J Hirsch (2006) Report on 2006 Update to Avoided Costs and E3 Calculator, Prepared for the California Public Utilities Commission.*
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